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16. ABSTRACT The paper gives EPA's conclusions from analyses which led to the decision to propose percent reduction Federal new source performance standards (NSPS) to control air emissions of sulfur dioxide (SO2) from new industrial boilers. It summarizes the NSPS, proposed by EPA on June 19, 1986. The NSPS would require boiler owners to reduce SO2 emissions by 90% and meet an emission limit of 1.2 lb/million Btu of heat input for coal-fired boilers, and 0.8 lb/million Btu for oil-fired boilers. In developing the NSPS, several regulatory options were considered, from standards that could be met by firing low sulfur fuels to those that would require flue gas treatment. The environmental, economic, and cost impacts of each option were analyzed. National impacts were estimated by a computer model that projects the population of new boilers over the 5-years following the proposal, predicts the compliance strategy that will be used to comply with the particular option (always assuming that the lowest cost compliance method will be selected), and estimates the resulting emission reductions and costs. Impacts on specific industries and on model boilers were also analyzed.

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Sulfur Dioxide	Stationary Sources	07B
Boilers	Industrial Boilers	13A
Standards		14G

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JOURNAL ARTICLE

Development of Federal Air Standards to Reduce Sulfur Dioxide Emissions from New Industrial Boilers

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Federal new source performance standards to control air emissions of sulfur dioxide from new industrial boilers were proposed by EPA on June 19, 1986. These standards would require boiler owners to reduce SO_2 emissions by 90 percent and meet an emission limit of 1.2 lb/MM Btu of heat input for coal-fired boilers and 0.8 lb/MM Btu for oil-fired boilers. In developing these standards, several regulatory options were considered, from standards that could be met by firing low sulfur fuels to standards that would necessitate flue gas treatment. The environmental, economic, and cost impacts of each option were analyzed. National impacts were estimated by a computer model that projects the population of new boilers over the 5-year period following proposal, predicts the compliance strategy that will be used to comply with the particular option (always assuming that the lowest cost method of compliance will be selected), and estimates the resulting emission reductions and costs. Impacts on specific industries and on model boilers were also analyzed. This paper focuses on these analyses and their results. The Agency's conclusions from these analyses, which led to the decision to establish percent reduction standards, are provided, and the proposed SO_2 standards are summarized. The proposed standards also include an emission limit for particulate matter from oil-fired boilers (0.1 lb/MM Btu). However, this article focuses only on the SO_2 standards.

Federal air emission standards to control emissions of sulfur dioxide (SO_2) from new industrial steam generating units were recently proposed in the *Federal Register*. Specifically, the standards will apply to new steam generating units with heat input capacities above 100 million Btu per hour (MM Btu/h) for which construction, modification, or reconstruction begins after June 19, 1986, the date on which the standards were published.

Industrial boilers are the second largest source of SO_2 emissions nationwide (utility boilers are the largest source). A single coal-fired boiler typically emits from 650 tons (for a boiler with 100 MM Btu/h heat input capacity) to greater than 5,000 tons of SO_2 per year (for a boiler with heat input capacity of 800 MM Btu/h). The recommended standards will reduce SO_2 emissions from new boilers by about 300,000 tons per year in the fifth year that the standards are in effect.

In developing these standards, a number of regulatory options were considered. These options include requiring emissions to be reduced to various levels (i.e., compliance with emission limits) and requiring that emissions be reduced by specified percentages. Emission limits would most likely be achieved by firing low sulfur fuels; percent reduction requirements would most likely be achieved by flue gas desulfurization (FGD). Some boiler owners may elect to fire natural gas to avoid being required to comply with an SO_2 standard.

This paper discusses the major regulatory options that were considered and presents the environmental and cost impacts projected for those options. The Agency's conclusions, based on its judgment of the reasonableness of the projected impacts, are also provided. Finally, the proposed standards are summarized.

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Applicability of the Standards

The SO_2 emission standards will apply to new steam generating units with heat input capacities above 100 MM Btu/h that are not covered under the current standards for utility boilers. These steam generating units, or boilers, may fire coal, oil, or a mixture of these sulfur-bearing fuels with other nonsulfur-bearing fuels such as wood, natural gas, or municipal solid waste. Nonutility boilers with heat input capacities above 100 MM Btu/h are typically boilers used to provide steam for industrial processes such as automobile manufacture, petroleum refining, liquor distilling, and fruit and vegetable canning. Very large institutional and commercial boilers, such as those

used to heat universities or large shopping centers, may have capacities above 100 MM Btu/h and are also covered by these standards.

The standards, referred to as new source performance standards (NSPS), will apply only to new boilers, that is, 1) boilers for which construction begins after the date on which the proposed standards were published in the *Federal Register*, 2) boilers constructed prior to the date of proposal that are modified after proposal in a way that increases their emission rate, or 3) boilers constructed prior to the date of proposal that are rebuilt after proposal to such an extent that the cost to rebuild exceeds half the cost of replacing the boiler with a comparable new one.

Regulatory Options Considered

In developing regulatory options for consideration, the Clean Air Act requirements pertaining to NSPS for fossil-fuel-fired stationary sources were followed. Section 111(a) of the Act, as amended in 1977, states that NSPS for fossil-fuel-fired sources shall establish allowable emission limitations *and* require the achievement of a percentage reduction in emissions. The Act also requires that NSPS reflect the degree of emission limitation and percentage reduction that is achievable through application of the best technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any health and environmental impacts not related to air quality, and energy requirements. Thus, the Clean Air Act mandates the establishment of both emission limits and percent reduction requirements, unless the impacts of such limits or requirements would be unreasonable.

Regulatory options included 1) establishing emission limits that could be met by firing fuels with various sulfur contents and 2) requiring that emissions be reduced by specified percentages, such as 50, 70, and 90. The alternatives for oil-fired boilers included emission limits of 0.8 lb SO_2/MM Btu and 1.6 lb SO_2/MM Btu, percent reduction requirements of 70 and 90 percent, and combinations of percent reduction requirements with emission limits of 0.3 and 0.8 lb SO_2/MM Btu.

Regulatory alternatives for coal-fired boilers were structured in the same manner as for oil-fired boilers. The emission limits considered for coal-fired boilers were 1.2 and 1.7 lb SO_2/MM Btu. The percent reduction requirements included were 50, 70, and 90 percent. Percent reduction requirements combined with emission limits of 0.6, 0.9, and 1.2 lb SO_2/MM Btu were also evaluated.

Consideration of Impacts

Annual reductions in SO_2 emissions and annualized compliance costs were projected for each regulatory alternative. The cost effectiveness (dollars per ton of SO_2 removed) of each option was calculated as well as the incremental cost effectiveness of each option compared to the next less stringent option. These impacts were analyzed on both a national basis and on the basis of model boilers reflecting a range of representative sizes, capacity utilization factors, and geographic locations.

In addition, the potential economic impacts of a percent reduction standard on seven industries considered likely to experience the most severe economic impacts were also assessed. These industries were selected due to the steam-intensive nature of their operations or the low utilization of their rated boiler capacity on an annual basis.

National Impacts Model

Potential national impacts were projected using the Industrial Fuel Choice Analysis Model (IFCAM) developed by Energy and Environmental Analysis, Inc. (EEA). IFCAM is an energy demand model that simulates the response of the industrial boiler market to changes in environmental and energy policies, fuel prices, and capital and operating costs.

IFCAM disaggregates total industrial fossil fuel demand, as projected by the Department of Energy (DOE),[1] into nine industrial categories. The energy demand by industry is partitioned into process heat, existing boiler demand, and new boiler demand based on historical patterns and projected industry-specific growth rates. The impact analysis focused only on the projected new boiler demand. The aggregate new boiler demand was partitioned into energy cells (a group of boilers with similar characteristics) having various size and capacity utilization attributes. The energy cells were then sited in Air Quality Control Regions to simulate the diversity of existing air pollution regulations across the nation.[2]

Once energy demand is disaggregated, IFCAM calculates the net present value of each combination of fuel and pollution control equipment over a 15-year period. Cost algorithms for pollution control equipment are used to determine the minimum cost design that satisfies the environmental constraints. The combination of fuel and pollution control equipment with the lowest after-tax net present value that simultaneously meets the environmental regulations under consideration is selected for each energy cell. Costs and emissions per energy cell are aggregated to estimate regional and national impacts.[2]

The fuel price projection is a critical determinant of national impacts. Fuel prices for the 1985 to 2000 time period were supplied as input data to IFCAM. Uncertainty in fuel prices over the next fifteen years was considered in this analysis through the use of two sets of residual oil and natural gas prices.[3] Coal prices, supplied by ICF, Inc.,[4] and total industrial energy demand were held constant in the two price projections. Distillate oil prices were not included because it was assumed that the price of distillate would be above the price of residual oil and natural gas in all regions.

The fuel price projection that represented EEA's "most likely" scenario is referred to as the Reference Case and reflects world oil prices of $28 per barrel ($/bbl) in 1990 (1982 dollars), $32/bbl in 1995, and $37/bbl in 2000. The world oil prices used in developing the reference case were provided by EEA using the World Oil (WOIL) forecasting model, a pricing model jointly developed by EEA and DOE that is used in preparing DOE's National Energy Policy Plan (NEPP). World oil price projections for the second fuel price scenario were taken directly from the NEPP for 1983 (Case B)[3] and reflect a substantial increase compared to the reference case. The second scenario is not presented here.

The methodology and assumptions used in the projections are presented in detail in a supporting document.[5] The methodology for developing residual oil prices used a simple refinery model for allocating production costs to different refinery products; the methodology for developing the natural gas prices used the Hydrocarbon Supply Model[6] to estimate the cost of new gas supplies.

The national impacts of the regulatory options are a function of the fuel price projections. Using the reference case fuel prices, IFCAM yields a mix of new boilers in which residual oil, natural gas, and coal compete for market shares. The market shares for these fuels are 65, 30, and 5 percent, respectively, under the regulatory baseline (reflecting national average State Implementation Plan requirements). The coal share changes only slightly under the alternative environmental regulations examined because coal is so clearly economical in the relatively small population of projected coal-fired boilers. As the severity of the regulatory alternatives increases, natural gas use increases while the use of residual oil decreases. Under a percent reduction requirement the market share for residual oil and natural gas are 30 and 65 percent, respectively.

Table I. Impacts of two regulatory alternatives: emission limits and percent reduction requirements.

	Emission reduction (tons/yr)	Annual costs (1000 $)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)
A. National impacts/Reference Case				
Emission limits only (0.8 lb/MM Btu for oil; 1.2 lb/MM Btu for coal)	173,000	57,000	330	330
90% reduction	263,000	133,000	505	840
B. Model Boiler Impacts (150 MM Btu/h, Region V)				
1. Oil-fired boiler				
Emission limit only (0.8 lb/MM Btu)	790	500	630	630
90% reduction	980	580	590	420
2. Coal-fired boiler				
Emission limit only (1.2 lb/MM Btu)	460	180	390	390
90% reduction	770	610	790	1,390

The boiler market in which oil and natural gas compete deserves a special caveat. This segment is considered a "swing" market, referring to the sensitivity of the market to fuel shifts. Large uncertainties exist in the relative pricing of natural gas to residual oil in long-term forecasts. Therefore, the impacts are used with caution where distinctions between oil and gas are important. The shifts between oil and gas represent general trends which are useful in assessing regulatory impacts. The split between coal and oil/gas, on the other hand, is considered more reliable.

National Impacts

The analysis of national cost impacts indicated that the annualized costs of firing one low sulfur fuel compared to firing another (e.g., firing a 1.6 lb SO_2/million Btu oil compared to a 0.8 lb SO_2/million Btu oil) are not substantially different, relative to the total costs of compliance. Similarly, the annualized costs of operating an FGD system at 70 percent sulfur removal versus 90 percent are not substantially different. Consequently, although the impacts were analyzed for all regulatory alternatives, the impacts discussed here are those associated with a particular low sulfur fuel alternative (i.e., emission limits of 0.8 lb/SO_2 MM Btu for oil-fired boilers and 1.2 lb SO_2/MM Btu for coal-fired boilers) and a 90 percent reduction requirement. These impacts are provided in Table I and reflect the Reference Case fuel price projections.

Sulfur dioxide emissions decrease from 279,000 tons in the baseline to 106,000 tons (an emission reduction of 173,000 tons) under a low sulfur fuel alternative. Emissions are reduced to 16,000 tons (an emission reduction of 263,000 tons) under an alternative requiring 90 percent removal of SO_2 for all oil- and coal-fired boilers. This additional reduction results from using flue gas desulfurization and from fuel switching (i.e., firing natural gas instead of oil).

National annualized cost impacts range from $57 million (1982 dollars) for a low sulfur fuel alternative to $133 million for a percent reduction alternative. The total annualized costs for the boiler population analyzed are estimated at $3.3 billion in the baseline.

National cost and emission impacts vary with the mix of fuels burned as well as with the regulatory alternatives considered. To the extent that the projected fuel mix changes with environmental regulations, the national compliance costs are to some degree mitigated, and the emission reduction is enhanced. National cost impacts are reduced by shifts to gas because firing natural gas is, in certain cases, less costly than flue gas treatment or firing a lower sulfur oil or coal. National emission reductions are greater because gas-fired boilers emit less SO_2 than coal- or oil-fired boilers with any existing pollution control technology.

Industry-Specific Economic Impacts

To determine whether NSPS would result in unreasonable economic impacts on specific industries, the impacts on seven industries expected to experience the most severe impacts were analyzed. These industries included beet sugar refining and fruit and vegetable canning (both of which typically use only a small percentage of their rated capacity on an annual basis), rubber reclaiming, automobile manufacturing, petroleum refining, iron and steel manufacturing, and liquor distilling (all of which employ steam-intensive operations).

The results of the industry-specific economic impacts analysis indicate that a percent reduction requirement (the most stringent and most costly regulatory alternative) would generally increase product prices by less than 1 percent. Return on assets would be expected to decrease, typically, by less than 1 percentage point.

Impacts on Model Boilers

The analyses of national impacts and industry-specific impacts discussed above examined the potential impacts of alternative standards at the national level and, within specific industries, at the manufacturing plant level. The regulatory analysis also examined the cost and emission impacts on typical boilers as a function of several parameters (e.g., boiler size and geographic location). Differences in geographic location were considered in analyzing the impacts on coal-fired boilers because the price of coal varies from region to region, reflecting local availability of coals with different sulfur contents. Differences in geographic location did not affect the cost impacts for oil-fired boilers, as the difference in price among oils of different sulfur content was assumed to be uniform for all geographic regions. Consequently, the impacts for oil-fired boilers were analyzed for only one geographic area (EPA Region V), while the impacts for coal-fired boilers were analyzed for two EPA Regions (Regions V and VIII). Region V was selected as representative of eastern coal prics; Region VIII was selected as representative of western coal prices.

This typical, or model, boiler analysis, unlike the national impacts analysis, should be viewed as a "worst case" analysis in terms of potential impacts since it does not consider the possibility of fuel switching (i.e., firing natural gas) as a compliance method.

Oil-fired boilers. The emission reductions achieved by standards based either on the use of low sulfur oil (emission limits) or on flue gas desulfurization (percent reduction requirements) were calculated for each representative boiler size. The first set of analyses discussed here is for a model boiler with a heat input capacity of 150 MM Btu/h, operating at 55 percent of rated capacity (on an annual basis), and located in EPA Region V. The impacts are compared to a regulatory baseline of 3.0 lb SO_2/MM Btu.

The impacts of a standard based on using low sulfur oil to meet an emission limit of 0.8 lb SO_2/MM Btu are provided in Table I. Annual SO_2 emission re-

ductions beyond baseline would be 790 tons/yr; annualized costs beyond baseline would be $500,000; the cost effectiveness would be $630/ton. A standard requiring a 90 percent reduction in emissions, for the same model boiler, would reduce SO_2 emissions by 980 tons/yr at annualized costs of $580,000. The cost effectiveness of a 90 percent reduction standard would be $590/ton; the incremental cost effectiveness of a 90 percent reduction standard compared to the emission limit standard would be $420/ton.

Coal-fired boilers. Impacts on model coal-fired boilers were analyzed in the manner described for oil-fired boilers. Potential impacts were examined for various sizes and geographic locations (EPA Regions V and VIII). Although the impacts varied for these two regions, the differences were not significant enough to affect the reasonableness of the impacts. For that reason, and to simplify the discussion, only the impacts for boilers located in Region V are provided here. The first set of analyses discussed below is for one model coal-fired boiler with a heat input capacity of 150 MM Btu/h, operating at 60 percent of rated capacity (on an annual basis). The impacts are compared to a regulatory baseline of 2.5 lb SO_2/MM Btu. These impacts are also provided in Table I.

The impacts of a standard based on firing low sulfur coal to meet an emission limit of 1.2 lb SO_2/million Btu would be the following: SO_2 emissions beyond baseline would be 460 tons/yr; annualized costs beyond baseline would be $180,000; the cost effectiveness would be $390/ton. A standard requiring a 90 percent reduction in emissions would reduce SO_2 emissions by 770 tons per year at annualized costs of $610,000. The cost effectiveness of a percent reduction standard would be $790/ton, and the incremental cost effectiveness compared to the low sulfur fuel standard would be $1390/ton.

Conclusions Based on the Analyses of Impacts

The following conclusions were drawn from the analyses of environmental and cost impacts described above. Based on the national impacts analyses, a 90 percent reduction standard would result in substantial emission reductions beyond those achieved by standards based on firing low sulfur fuels. Additional emission reductions achieved by a 90 percent reduction standard under the most likely fuel price scenario would be 90,000 tons in the fifth year. The additional costs would be $76 million, resulting in an incremental cost effectiveness of $840/ton. This incremental value is considered to be reasonable; thus no unreasonable impacts associated with a percent reduction requirement were identified on a nationwide basis.

The analyses of industry-specific economic impacts did not identify any unreasonable impacts associated with percent reduction requirements. Since percent reduction requirements are the most costly alternative considered, the impacts associated with an emission limit based on the use of low sulfur fuels would also be justifiable.

In judging whether the impacts of a percent reduction standard on individual boilers would be reasonable, primary consideration was given to the incremental cost effectiveness numbers. For oil-fired boilers, the incremental cost effectiveness number for a small boiler (heat input capacity of 150 million Btu/h) operating at the typical capacity utilization factor of 0.55 was $420/ton. For coal-fired boilers, the incremental cost effectiveness value for a small boiler (150 million Btu/h) operating at the typical capacity utilization factor of 0.6 was $1390/ton. The incremental cost effectiveness value of $420/ton is considered to be very reasonable; the $1390/ton value for coal-fired boilers is judged to be slightly high. However, in the case of coal-fired boilers, the national impact analyses indicate that boilers with heat inputs below 250 MM Btu/h are not likely to fire coal under a percent reduction standard. These smaller boilers would most likely fire natural gas to avoid installing FGD systems to control emissions produced by firing coal. Thus, in practice, the incremental costs associated with a percent reduction standard applied to small coal-fired boilers (less than 250 MM Btu/h) are not expected to be realized. The costs associated with fuel switching (firing natural gas instead of coal) are reasonable in light of the additional emission reduction achieved by firing natural gas.

In summary, the Agency concluded that the analyses of national impacts, economic impacts on specific industries, and impacts on model boilers did not identify any unacceptable adverse impacts associated with percent reduction requirements. No sizes, types, or other categories of boilers were identified for which a percent reduction requirement would have unreasonable impacts. Additional environmental impacts such as the impacts on liquid and solid waste were also evaluated, and no adverse impacts were found. The impact of fuel switching on the natural gas, coal, and oil markets was estimated to determine if there would be adverse energy impacts. The implementation of percent reduction standards could result in a decrease in national oil consumption of about 1 percent, an impact that is not considered unreasonable. A corresponding increase in natural gas consumption would have a negligible effect on the national availability of natural gas. The national impact analysis indicates that the impact of a percent reduction standard on nationwide coal use would be negligible. Thus, in accordance with Clean Air Act requirements for standards adopted for fossil-fuel-fired sources, the proposed standards require compliance with both an emission limit and a percent emission reduction requirement.

Selection of Standards

In selecting the appropriate percent reduction number, consideration was given primarily to the performance of demonstrated SO_2 emission reduction technologies and to the cost effectiveness of different percent reduction numbers (i.e., 50, 70, and 90). The selection of emission limits was based on accommodating the use of oil and coal with high sulfur contents.

Selection of the Percent Reduction Level

Over the past decade, the Agency has reviewed several types of wet and dry FGD systems, combustion modification techniques (such as fluidized bed boilers), and fuel pretreatment technologies suitable for the control of SO_2 emissions from industrial boilers. In 1978 and 1979 the Air and Energy Engineering Research Laboratory (AEERL) of EPA's Office of Research and Development developed a series of technology documents targeted for industrial boilers. For SO_2, the technol-

Table II. Long-term performance data for industrial wet FGD systems.

Type of FGD system	Location	Test duration, days	% Removal	% Reliability
Single pass sodium	GM-St. Louis	30	96.3	100
Dual alkali	GM-Parma	24	91.3	89.2
Dual alkali	GM-Parma	17	93.8	95.0
Lime	Rickenbacker	29	91.9	94.8
Limestone & adipic acid[a]	Rickenbacker	36	94.3	94.9

[a] Not reported in references cited in text; details available in EPA-600/7-82-065a. November 1982.

ogies investigated were coal cleaning, oil cleaning, synthetic fuels, fluidized bed combustion (FBC), and FGD.

Subsequently, EPA conducted an in-depth investigation of the costs and performance of wet FGD systems. Several 30-day monitoring tests were performed during the 1979–82 period by the Office of Air Quality Planning and Standards (OAQPS) and AEERL, and the combined results were presented in a paper by Sedman[7] and in an EPA document.[8] Table II summarizes the performance of wet FGD systems tested by EPA, and shows 90+ percent SO_2 removal for lime, buffered limestone, dual alkali, and once-through sodium systems, with correspondingly high reliabilities (95 percent on the average) for the test period.

In the early 1980s, two other technologies, dry FGD and FBC, entered commercial operation, necessitating an update of the Agency's technology reviews. In July 1984, EPA issued a report entitled Industrial Boiler SO_2 Technology Update Report[9] which summarized the status of both wet and dry FGD systems applied to industrial boilers. The data presented in this report included long-term reliability statistics as well as performance data. The results are summarized in Table III and show that the most widely applied SO_2 scrubbers, once-through sodium, have demonstrated typical reliabilities of 98–99 percent and SO_2 removals (based on short-term tests) of greater than 95 percent. Dual alkali scrubbers exhibited reliabilities of 90–99 percent and average SO_2 removals of 91 percent. Dry flue gas systems reported SO_2 removals of 75–95 percent and reliabilities of 80–95 percent, with steady improvement in reliability noted with increasing experience.

During this period EPA conducted two long-term SO_2 monitoring tests on dry FGD systems which resulted in 70 percent SO_2 removal (with 20 percent flue gas bypass) on a system firing 1–2 percent sulfur coal, and 80 percent removal on a 3 percent sulfur coal.[10,11] Since these pioneering efforts in the application of dry scrubbing, conversations with vendors reveal that up to 95 percent reliability and 95 percent SO_2 removal will be guaranteed contractually when operators agree to specific operational and maintenance procedures and conditions.[12]

EPA also conducted a similar survey of FBC systems and issued a report in September 1984 which revealed that many industrial fluidized bed combustors were being installed for fuel flexibility, not as a control strategy for sulfur oxides. Of the few units using FBC for SO_2 control, reported SO_2 removal efficiencies ranged from 80–95 percent at calcium-to-sulfur (Ca/S) ratios of 3 to 1.[13] EPA conducted two long-term tests of fluidized bed combustors which showed 85 and 89 percent SO_2 removals on higher sulfur coals and Ca/S ratios of 3 to 1.[14,15]

Based on these data, the Agency has concluded that demonstrated control technologies such as wet FGD systems, lime spray dryers, and FBC systems can achieve at least 90 percent SO_2 removal over a 30-day averaging period. Since the evaluation of the performance of various FGD systems and combustion modification technologies indicates that 90 percent SO_2 removal is achievable, and the Clean Air Act requires that NSPS be based on the best system of continuous emission reduction considering costs, 90 percent was selected as the appropriate level for the percent reduction requirement. This choice was further supported by the fact that the cost effectiveness of operating an FGD system at 90 percent sulfur removal is better than the cost effectiveness of operating at lower percent sulfur removals. Operating at a lower percent removal efficiency provides savings in chemicals, utilities, and waste disposal costs, but these savings are small relative to total costs. However, the differences in emission reductions achieved by FGD systems operating at different sulfur removal efficiencies are substantial. For example, an oil-fired boiler with a heat input capacity of 150 MM Btu/h and firing a high sulfur oil (3.0 lb SO_2/MM Btu) would emit approximately 410 tons of SO_2 per year if the FGD were operated at 50 percent sulfur removal. The annualized costs would be $5 million, and the cost effectiveness would be $680/ton compared to baseline. For the same size boiler, firing the same fuel, but operating at 70 percent sulfur removal, the annual emissions would decrease by 164 additional tons per year at additional costs of $60,000 per year. The average cost effectiveness would be $620/ton. Increasing the sulfur removal efficiency to 90 percent would further reduce SO_2 emissions by an additional 164 tons per year at additional costs of $60,000. The cost effectiveness of a 90 percent removal efficiency would be $580/ton.

Table III. Results of industrial FGD survey.

Scrubber type	Reliability		SO_2 removal	
	No. surveyed	Avg. %	No. surveyed	Avg. %
Sodium	256	99	26	96.4
Dual alkali	3	95.5	6	91.0
Lime	1	95		
Spray dryers	4	87	4	88.0

Selection of Emission Limits

One of the objectives of the Clean Air Act amendments of 1977 was to encourage the use of locally available high sulfur coal, and this objective was taken into consideration in selecting the emission limit for coal-fired boilers. Similarly, the emission limit for oil-fired boilers was established at a level that would not preclude the use of very high sulfur oils.

An analysis of U.S. coal reserve data indicates that almost all (98 percent) domestic coal reserves could be used to comply with a standard requiring a 90 percent reduction in SO_2 emissions with an accompanying emission limit of 1.2 lb SO_2/MM Btu. An emission limit of 0.6 would restrict coal use to about 80 percent of domestic coal reserves. To provide for the use of essentially all U.S. coal reserves, an emission limit of 1.2 lb SO_2/MM Btu was selected as the emission limit to accompany the percent reduction requirement for coal-fired boilers.

Review of data on fuel oils currently produced by U.S. refineries indicates that the sulfur content of residual oils produced from particularly heavy crudes or oils recovered from tar sands and oil shales could result in uncontrolled SO_2 emissions of 8.0 lb/MM Btu. More typical residual oils would emit at lower levels than 8.0 lb/MM Btu. To allow for the use of all residual oils, an emission limit of 0.8 lb SO_2/MM Btu was selected as the limit included with the 90 percent reduction requirement for oil-fired boilers.

Standards for Emerging Technologies

The standards discussed above reflect the level of emission reduction achievable by conventional SO_2 emission reduction technologies. It may be questionable, however, whether these standards are achievable by emerging technologies at their current state of development.

To increase the likelihood of owners' electing to use emerging technologies, a less stringent percent reduction requirement was proposed for emerging technologies. The requirement for emerging technologies is a 50 percent reduction in SO_2 emissions. This level is considered low enough to encourage the use of emerging technologies. However, to minimize the potential for very high levels of SO_2 emissions at facilities using emerging technologies, an accompanying emission limit of 0.6 lb

Table IV. Summary of SO_2 standards.[a]

Fuel	Control system: Conventional (wet FGD, fluidized bed, lime spray drying) % SO_2 removal	Conventional SO_2 limit	Emerging % SO_2 removal	Emerging SO_2 limit
Coal	90	516 ng/J (1.2 lb/MM Btu)	50	256 ng/J (0.6 lb/MM Btu)
Oil	90	344 ng/J (0.8 lb/MM Btu)	50	172 ng/J (0.4 lb/MM Btu)
Mixed coal capacity factor >0.3	90	516 ng/J (1.2 lb/MM Btu) coal-fired portion; 344 ng/J (0.8 lb/MM Btu) oil-fired portion	50	256 ng/J (0.6 lb/MM Btu) coal-fired portion; 172 ng/J (0.4 lb/MM Btu) oil-fired portion
Mixed coal capacity factor <0.3; non-fossil fuel capacity factor >0.10	NA	516 ng/J (1.2 lb/MM Btu) coal-fired portion	NA	516 ng/J (1.2 lb/MM Btu) coal-fired portion

[a] If SO_2 <86 ng/J (0.2 lb/MM Btu) for oil-fired units, all above conditions are considered met. A 30-day rolling averaging time is used for determining compliance with the SO_2 standards on a continuous basis.

SO_2/MM Btu was proposed for coal-fired boilers, and a limit of 0.4 lb SO_2/MM Btu was proposed for oil-fired. Emission limits at these levels restrict the use of emerging technologies achieving only the minimum 50 percent reduction to facilities firing low sulfur fuels. To the extent that an emerging technology achieves greater than 50 percent reduction, fuels with higher sulfur contents can be fired without exceeding the emission limits.

Other Provisions

The addition of standards formulated to accommodate emerging technologies represents one of several special conditions that the Agency addressed in the NSPS. For example, special provisions are included for boilers that fire coal in combination with nonsulfur-bearing, nonfossil fuels such as wood or municipal solid waste. These boilers, referred to as mixed-fuel-fired boilers, are exempt from the percent reduction requirements if three conditions are met. These conditions are: 1) The amount of coal fired in the boiler on an annual basis does not exceed 30 percent of the boiler's nameplate capacity, 2) the amount of nonsulfur-bearing fuel fired on an annual basis represents 10 percent or more of the nameplate capacity, and 3) the boiler is subject to a federally enforceable permit limiting operation of the boiler to the first two conditions.

The standards allow credit for fuel pretreatment, such as physical coal cleaning or hydrodesulfurization of oil, to be applied toward the 90 percent reduction requirements. In cases where the emissions from oil-fired boilers do not exceed 0.2 lb/MM Btu, full credit for 90 percent sulfur removal (achieved at the refinery) may be applied toward the percent reduction requirement. These and other special provisions are fully described in the proposed standards (51 FR 22384; June 19, 1986).

Summary

The proposed SO_2 emission limits and percent reduction standards are summarized in Table IV. The NSPS was proposed in the *Federal Register* on June 19, 1986. Final standards for SO_2 emissions from industrial boilers are scheduled for publication in the *Federal Register* in December 1987.

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